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**Citation for published version:**

Blake, S, Taylor, P, Dent, C & Miller, D 2015, 'Quantifying the contribution of wind farms to distribution network reliability', *Wind Energy*, vol. 18, no. 5, pp. 941-953. <https://doi.org/10.1002/we.1741>

**Digital Object Identifier (DOI):**

[10.1002/we.1741](https://doi.org/10.1002/we.1741)

**Link:**

[Link to publication record in Edinburgh Research Explorer](#)

**Document Version:**

Peer reviewed version

**Published In:**

Wind Energy

**Publisher Rights Statement:**

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# Quantifying the Contribution of Wind Farms to Distribution Network Reliability

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## ABSTRACT

The reliability of power supply to distribution network customers can be increased by embedded generation, including wind farms. The value of this increase in reliability needs to be evaluated, and national standards such as the GB security of supply standard P2/6 seek to do so. This paper appraises the capacity credit evaluation methodology in P2/6, and outlines an alternative methodology to integrate generation with load more effectively, taking into account the topology, loading and reliability of the surrounding network. It concludes that under certain circumstances the presence of embedded wind generation can allow the deferral of costly network reinforcement projects, but that the time for which reinforcement can reasonably be deferred is a function not only of the generators themselves but also of the surrounding network.

## KEYWORDS

Security of supply standards; Wind farm capacity credit; Network reinforcement deferral.

## 1. Introduction

The value of distributed generation for increasing the reliability of power supply to customers across electrical distribution networks is a well established aspect of energy planning policy. This value can be of particular significance for customers connected to remote parts of the network where there is generation in the vicinity. In remote locations in the UK nearby generation is typically wind powered, in which case appropriate allowance has to be made for generators' variability if their effective contribution to network reliability is to be accurately assessed.

Appropriately quantifying the contribution that distributed generation can make to network reliability is important, in particular at a local level. If this contribution is overvalued, then the frequency and duration of interruptions to customer supply in that locality could increase to an unacceptable level. Conversely, if this contribution is undervalued, then unnecessary and costly capital investment could be incurred, with consequent price rises for customers. Given that the level of capital investment for a Distribution Network Operator (DNO) can exceed £100M per year, it is essential that accurate estimates ensure that appropriate investment is carried out in the right year to provide agreed levels of network reliability and security of supply.

Section 2 of this paper looks at previous work that has been carried out to analyse the value of distributed wind generation, in particular as regards distribution network reliability, in a number of different countries. In some countries there are national reliability design standards, and Sections 3 and 4 look in more detail at one example, the GB standard P2/6 which evaluates the capacity credit that should be

allowed for such generation, and which has proved to work well within the GB power system.

The contribution that wind generation can make to network security, which can then be used to justify the deferral of network reinforcement, is often expressed as a function of the wind generators only, regardless of the topology, loading and reliability of the surrounding network. This paper argues that such network characteristics need to be taken into account, and develops in Section 5 an alternative, location-specific methodology based on effective load carrying capability (ELCC) for doing so. In Section 6, an exemplar case study demonstrates that the time for which reinforcement can justifiably be deferred as a consequence of embedded wind generation varies significantly according to these network characteristics. Conclusions are presented in Section 7.

Such an analysis is particularly timely in view of the increasing need globally to increase proportions of renewable generation while maintaining levels of reliability and without unduly increasing costs. For example, within GB there is an impending fundamental review and possible consequent revision of the security of supply standard. It is essential that any new standard allows accurate estimates to be made of the effective contribution of wind generation to location-specific network reliability. The methodology presented in this paper seeks to determine just how long costly network reinforcement can be deferred as a function, not only of the capacity and intermittency of embedded wind generators, but also of the topology, loading and reliability of the surrounding network.

## **2. Background**

A good summary of the value of wind generation in a power system is given in [1], which evaluates this under 5 headings:

1. Operating cost value, generally positive, as the use of fossil fuel and more labour-intensive fossil fuel generators is avoided.
2. Loss reduction value, also generally positive, as wind farms supply local customers who are typically closer to the wind farm than they were to a more remote, large fossil fuel generating station.
3. Control value, which is the capability of a power plant to follow demand. This is generally negative, due to the inherent intermittency of the wind, as well as the possible power quality factors analysed in [2].
4. Capacity credit. Where new generating plant is added to a system, there is generally a decreased loss of load probability (LOLP) for customers, who may experience reduced disconnection frequency or duration. This benefit is likely to be less for an intermittent generator such as a wind farm than for a conventional generator where the fuel supply can be controlled, but it is still significant, and can be quantified.
5. Grid investment value. If the capacity credit is large enough, and depending on the security of supply standard adopted, it may be possible to defer capital expenditure that would be necessary in the absence of generation by a number of years. Conversely, it may be necessary to invest sooner in order to accommodate the new generation.

Early studies of the potential for wind generation often used Markov state analysis to predict probability distributions and possible time series for power generated [3,4,5]. These studies became increasingly robust as they were confirmed by actual wind farm data, and their approach has been built on by more recent work, often making use of Monte Carlo simulation to produce relevant time series [6-10].

The concept of generator persistence has proved to be important, as described by Holttinen and Hirvonen [11] with particular reference to the Nordic power system.

The conclusions from these studies have been varied. In one study across a wide Canadian transmission network, the case is made for network reinforcement to ensure that all potential generation can be satisfactorily dispatched [8]. The need for accurate and reliable wind speed data is stressed, with options to use simpler modelling techniques when such data is sparse [7]. The potential to substitute low carbon wind energy for high carbon fossil fuels is one motivation for making the most effective wind farm connections, possibly supplemented by active network management in the control room [12].

Some studies have also included analysis of the more localised contribution of wind generation to distribution network reliability. In an early paper, Hegazy et. al. evaluate embedded generation which is not necessarily wind-powered, using a state duration sampling approach with a Monte Carlo based method and a case study based on an IEEE 33 kV and 11 kV test network [13]. They conclude that for their data the amount of unsupplied load can be reduced by around 80%. This analysis was further developed by El-Khattan et. al. [14,15], and by Singh et. al. [16], using Monte Carlo simulation based on Newton-Raphson load flow analyses for each hour of a representative day. Singh et. al. conclude that this time dependency is an essential component for calculating the possible deferral time for network reinforcement. Li and Sabir [17], using an IEEE representative 34-bus system, found that distribution network reliability could be significantly improved by distributed generation relieving overloaded circuits under fault conditions elsewhere on the network.

In [4], a time-sequential simulation of a rural network is used to determine how large a wind farm should be to achieve a specified increase in reliability. The metric used for this study is the expected energy not supplied (EENS), which can be one measure of increased reliability. A similar approach is adopted by [18], which also considers issues of voltage rise and system power losses. Duttagupta and Singh [19] use a path augmenting max. flow algorithm to determine the optimal placement of distributed generation for maximising network reliability, using frequency of loss of load and EENS as metrics.

Although many of these cited studies consider embedded generation in general rather than wind generation in particular, the methodology used is similar, provided that adequate allowance is made for the particular nature of wind generators' intermittency.

### **3. Security of Supply Standards**

Not all countries have nationwide formal standards for security of supply at distribution level. In the US, for example, the issue of integrating distributed generation was addressed in a report [20], but the findings of that report have advisory status only. A study in South Africa concluded that national standards were almost non-existent [21]. This study also highlighted that large customers might want, and be prepared to pay for, different standards of reliability from the majority of smaller, domestic customers. Bollen et. Al. [22] found that there seemed to be a sharp threshold value for customer satisfaction regarding reliability of supply. Billinton and Pan [23] show that the Canadian regulatory system is well-developed, but based on a system where utilities are both suppliers and distributors, unlike the UK where generation, transmission, distribution and supply were systematically unbundled in the 1990s.

In the UK, including Great Britain, there is a formal design standard P2 regarding security of supply, and this standard includes capacity credit for embedded generation, including wind generation. It is instructive to analyze this standard in some detail, not only for its own sake but also as an example of such standards that have been implemented, or that might be implemented in the future, in other countries.

The GB standard for security of supply was formulated, largely in its present form, in the 1970s as version P2/5. This standard sets out, for demand groups of different size, the restoration requirement, in terms of proportion of customers and of maximum permitted restoration time following a single outage (n-1) and also, for demand groups exceeding 100 MW, following a second outage (n-2), typically a fault on one circuit coincident with planned maintenance on another circuit. These requirements were continued unchanged in the current P2/6, and are summarised in Table 1 [24].

<i>Class of supply</i>	<i>Range of group demand</i>	<i>Minimum demand to be met after first circuit outage (n-1)</i>	<i>Minimum demand to be met after second circuit outage (n-2)</i>
A	Up to 1 MW	In repair time (Group Demand)	NIL
B	Over 1 MW to 12 MW	(a) In 3 hours (Group Demand minus 1 MW) (b) In repair time (Group Demand)	NIL
C	Over 12 MW to 60 MW	(a) Within 15 minutes (Smaller of Group Demand minus 12 MW and 2/3 Group Demand) (b) Within 3 hours (Group Demand)	NIL
D	Over 60 MW to 300 MW	(a) Immediately (Group Demand minus up to 20 MW automatically disconnected) (b) Within 3 hours (Group Demand)	(c) Within 3 hours (For Group Demands greater than 100 MW, smaller of Group Demand minus 100 MW and 1/3 Group Demand) (d) Within time to restore arranged outage (Group Demand)
E	Over 300 MW to 1500 MW	(a) Immediately (Group Demand)	(b) Immediately (All customers at 2/3 Group Demand) (c) Within time to restore arranged outage (Group Demand)
F	Over 1500 MW	See GB SQSS regulations	See GB SQSS regulations

*Table 1 – P2/6 requirements for each demand group*

The primary purpose of P2/6 is as a design standard. If, for example, supplies to a demand group of size 15 MW could not be fully restored within 3 hours following a single circuit outage, that group would be in breach of the standard. The regulator could then require that capital investment be undertaken to improve security of supply. This might typically be achieved by installing a second circuit (overhead line and/or underground cable, a transformer and associated switchgear, control and protection equipment). Other possibly less costly remedies might include permanent load reconfiguration, or automated post-fault circuit transfer. It could also be the case that the availability of local generation on the network could increase reliability sufficiently to avoid the breach of standard P2.

One of the main uses of P2 is to determine, in an area where demand is increasing, for how long the existing network will be adequate, and in what year it will need to be reinforced in some way.

Version P2/5 included allowances for embedded generation, but it was based on the types of generation common in the 1970s, in particular small shift-operated coal burning plant. Around the year 2000, it was seen that this assumption was no longer appropriate, and that P2 should therefore be modified to address this, including recognising the growing number of wind farms.

A working party was set up to review P2, in particular its treatment of generation capacity credit, and a sequence of reports was produced [25,26,27]. They initially recommended that the underlying methodology of P2/5 should be retained, namely that the capacity credit allowed for a generator should be the same as the capacity of an additional circuit that would provide the same reliability, measured as a reduction in the EENS. This can be expressed in general by

$$[EENS] = \sum_t E[(D_t - Y_t)_+] = \sum_t E[(D_t - x^*)_+] \quad (1)$$

where  $D_t$  and  $Y_t$  are the time-dependent random variables for demand and generation respectively, summed over different generators and types where necessary, and the subscript  $_+$  indicates that only positive values are taken. The summation of expected values over time in (1) then gives the value of EENS. The equivalent circuit capacity  $x^*$ , also called the Equivalent Firm Capacity (EFC) can then be calculated as that fixed value of circuit capacity which will give the same expected value of EENS as the proposed generators. However, as will be discussed later, this effectively assumes an (n-2) state with rescaled demand, and therefore addresses a different problem from P2/6, which is primarily concerned with the (n-1) state.

The principle of EFC is easily stated, but is not always so easy to apply to a given network. As regards wind generators, one issue was the lack of adequate data at the time the reports were written. Assumptions had to be made about average capacity factors, taking into account both the availability of wind, and the availability of the turbines themselves.

The question of seasonality arose. Given that energy demand is significantly greater in winter, should the wind farms be given credit based on a year-round average capacity factor, or on one based on winter wind speeds, which are likely to be higher? Either is possible, but it is not always clear which is the more appropriate.

Persistence was also an important factor. If an outage is expected to last 0.5 hours, the probability of a wind generator delivering a certain power throughout that time can be estimated. If, however, the outage is expected to last for 3 hours, there is a higher probability that the wind speed will drop at some time during those 3 hours, and therefore the value of the wind generator will be less if it is required for 3 hours than if it is only required for 0.5 hours, and this fact must be reflected in the capacity credit allowed.

Sensitivity to the profile of wind farm output was also addressed. An overall capacity factor of 30% could be attained from different patterns of  $D_t$  in (1), with different proportions of time at zero output, at full capacity output, and at a range of levels in between. It was found that the effect on EENS was not greatly affected by the profile, although this was on the implicit assumption that, network-wide, all energy supplied by the generators was needed and could be used to relieve any shortfall. At a local level, however, EENS is a function of the topology, circuit

ratings and demand profile of the surrounding network, as will be discussed in more detail in the following sections of this paper.

The working party reports had initially anticipated a fundamental review of the way in which generation was credited, adopting a probabilistic approach and incorporating a wide range of significant factors. In the event, however, time constraints and perhaps engineering conservatism limited the changes that could be incorporated. The result, as applied to wind farms in P2/6, is shown in Table 2 [24]. In Table 2, the F-factor is the proportion of the total nameplate rating of the wind farm that can be allowed as capacity credit for a given value of persistence. So, for example, if a wind farm with 4 turbines of capacity 2.5 MW each is required to mitigate a 3 hour outage (as recommended in P2/6 for switching operations involving this size of demand group), its capacity credit should be based on an F-factor of 24%, and is therefore 2.4 MW.

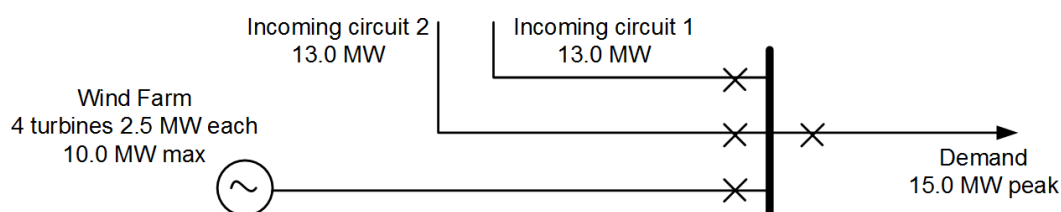
Persistence (hours)	0.5	2	3	18	24	120	360	>360
F-factor (%)	28	25	24	14	11	0	0	0

*Table 2 – Capacity credit F-factors for wind generators in P2/6*

It should be noted that these F-factors were calculated using historic data from a sample of just 3 wind farms, and on the assumption that peak demand is equal to generator capacity [28], and based on an (n-2) condition. However, they are generally applied in the (n-1) condition, and to a network where peak demand is generally not equal to generator capacity.

The application of this capacity credit can best be illustrated by a worked example, following the approach adopted in [27]. Suppose the demand group of 15 MW was fed by two circuits each of capacity 13.0 MW, with no lower voltage interconnection outside the group, as shown in Figure 1. The loss of one circuit, at a time of peak demand (which is always assumed in P2) would leave a shortfall of 2.0 MW. If the fault causing the loss could not always be repaired or restored within 3 hours, then the demand group would be in breach of P2.

If, however, the 4 turbine wind farm described above were connected to the secondary busbar supplying the demand group, then its capacity credit of 2.4 MW would be deemed to be sufficient to supply the shortfall, and the demand group would no longer be in breach of P2, although shortfalls could still occur in practice whenever wind farm output falls below 2.0 MW. This means that capital investment to uprate the two supply circuits above 13.0 MW, or to build lower voltage interconnection which would permit customer transfer, either permanent or post-fault, would no longer be required under P2/6 following the commissioning of the 4 turbine wind farm.



*Figure 1 – Worked example of demand group with wind farm*

#### 4. Appraisal of Capacity Credit Evaluation in P2/6

The underlying studies recommended, and P2/6 uses, the metric of EENS, and the methodology of comparing any generator with an equivalent circuit according to this metric, to calculate the allowed capacity credit. Other concepts which were recommended by the studies and are incorporated into P2/6 include the definition and use of persistence, and the use of winter generation data to match the expected winter peak loads.

A number of simplifications have been made by using the P2/6 look up table (Table 2) to evaluate capacity credit. This is acknowledged in P2/6, which allows an estimate to be made based on generic generation profiles or on actual time series data from an existing wind farm. Supporting instructions are available for these more detailed data-incorporating spreadsheet calculations [28, 29]. This addresses the issue of using essentially a single estimate of capacity factor for all wind farms, regardless of location. However, practical experience of using these alternative approaches, in a study including 28 separate wind farms across the North East of England with average capacity factor 0.24, has indicated that their impact on the final results is generally marginal [30].

A number of issues, some of which were explicitly raised and discussed in [25], have not been fully incorporated into P2/6. Those of particular relevance to the evaluation of wind farm capacity credit include:

1. The capacity factor for a given wind farm depends not only on the wind regime, but also on the availability of individual turbines, and of common assets that affect the availability of a group of turbines. Measuring and incorporating these availabilities as a distinct input has been addressed [31, 32], but is not separately identified in the P2/6 methodology. It is essential that the probability distribution for  $Y$  incorporates these availabilities appropriately. The effective capacity factor can also be increased by the incorporation of additional assets, in particular electrical energy storage (EES), and a number of studies have evaluated the beneficial effect of combining wind generators with EES [33-36].
2. The use of winter generation data is generally appropriate, but there will be locations where the proportionate reduction in demand in summer is less than the proportionate decrease in relevant circuit thermal ratings. In such cases, the summer constraints may be the more critical, and the appropriate probability distribution would therefore be based on summer generation data. In other cases, a (possibly weighted) average value throughout the year would be more appropriate.
3. The commercial environment in which a generator operates was also discussed, in particular the possibility that it might not be operational when needed, although technically available. This applies in particular to CCGT and CHP plant, but could also apply to wind generation.
4. The studies underlying the formulation of P2/6 explicitly addressed the potential of embedded generation, in particular during switching operations, for deferring costly network reinforcement [27]. This is illustrated with respect to generic networks, and can be further refined by the use of uncertainty



analysis [37]. However, the underlying methodology of (1) excludes details of network topology, such as existing infeed circuit capacity, which therefore does not feature in the F-factor calculations. In effect, the F-factor calculation is of EFC under (n-2) conditions.

5. The presence of generation on a network does not guarantee that it can be used in practice to relieve shortfalls at other locations on that network. In particular, there may be thermal or voltage constraints that prevent or limit such use.
6. While P2/6 addresses peak loading only, other loading characteristics, including power factor and demand profiles through day, week and year, are significant in determining the pattern of possible shortfall, and therefore whether network reinforcement could indeed be deferred.
7. Actual levels of network reliability are specifically excluded from P2/6 assessment. The probability of (n-1) and (n-2) situations actually occurring is a significant component in calculating reliability, but in P2/6, the same reliability requirements apply to long, exposed overhead line circuits with relatively high failure rates serving rural communities as apply to short underground circuits in urban areas with relatively low failure rates.
8. There also appears to be an implicit assumption in P2/6 that the two outages constituting an (n-2) event are independent, and that therefore an (n-2) event is less likely than an (n-1) event by some orders of magnitude. . In fact, they are highly dependent, to the extent that around 20% of all fault events on double circuits at extra high voltage (EHV) (33, 66 and 132 kV in GB) involve outages of both circuits [38]. One consequence of this dependency is that often most of the EENS in double circuit networks occurs following (n-2) events rather than (n-1) events. This proportion can exceed 99% in certain cases [39]. However, as Table 1 shows, for demand groups below 100 MW, only the less likely (n-1) events are addressed by P2/6. The value of wind generation following an (n-2) event depends on whether that event causes islanding of the load, or just network weakening (there may or may not be a small amount of lower voltage interconnection), and if the network is islanded, whether the wind generators can continue to operate. This is a crucial consideration, as was identified in the underlying studies [25, page 65].
9. The underlying methodology of (1) to calculate an equivalent firm capacity  $x^*$  related to existing demand is then being used to calculate F-factors, which are in turn used to estimate the additional demand that could be accommodated for the same reliability, also called the Effective Load Carrying Capability (ELCC). While calculations of EFC and ELCC can give similar values for the addition of small generators, their values tend to diverge as generator size increases. The F-factors are essentially calculated as EFC with the network in the (n-2) state, but are then used in circumstances where ELCC might be more appropriate, and typically with the network in the (n-1) state.

In the light of all the above points an alternative methodology has been developed to address the issues raised. This methodology is detailed in the following section.

## 5. Methodology to Integrate Generation with Load

The main issue that is not directly addressed by P2/6 is that the real value of wind generators depends on the relative size of the demand shortfall, which is a function of the topology, loading and reliability of the surrounding network, as well as of the capacity, intermittency and reliability of the generators themselves. This shortfall is a component of the EENS calculation, which can be expressed, using the nomenclature and methodology detailed in [39], and as developed by the authors, as

$$[EENS] = \sum_t E[(D_t + d^* - X_t - Y_t)_+] = \sum_t E[(D_t - X_t)_+] \quad (2)$$

Equation (2) can be directly compared with (1), with  $D_t$  representing demand and  $Y_t$  representing generation. However, (1) and (2) differ in two critical respects.

The first is that substituting the possible demand increment  $d^*$  on the left of the equation (which is ELCC), instead of the equivalent circuit capacity  $x^*$  on the right of the equation (which is EFC), makes possible demand growth the focus. This seems to be more in keeping with the intention of P2/6, and with the practical issues faced by DNOs, rather than with the modelling assumptions adopted.

The second difference is the inclusion on both sides of the equation of the actual incoming circuit capacity  $X_t$ . Because only positive values are taken, as indicated by the subscript  $_+$ , there will be times when  $X_t$  contributes to one side of the equation, but not to the other.

In the generic case shown in Figure 1, where supply is provided by 2 circuits each of thermal rating  $c$ , as in [39],  $X_t$  takes the distribution

$$\begin{aligned} p(X = 2c) &= p_{N-0} \\ p(X = c) &= p_{N-1} \\ p(X = 0) &= p_{N-2} \end{aligned} \quad (3)$$

Where  $p_{N-0}$  is the probability of being in the network intact, (n-0) state, and  $p_{N-1}$  and  $p_{N-2}$  are the probabilities of being in (n-1) and (n-2) states respectively. These probabilities can be estimated either from historic data for the particular circuits, if available, or from a theoretical calculation based on the number of assets contained in each circuit, individual asset condition and generic failure rates, or from a combination of the two. It should be noted that a probabilistic approach of this nature is in contrast to the generally deterministic approach adopted by P2/6, as discussed in points 7 and 8 of the previous section. In P2/6, the (n-1) and (n-2) situations are treated as completely separate cases (as in Table 1), and peak loads are assumed throughout.

In a more complex case, there may be a small quantity of lower voltage interconnection, of total rating  $S$ , a variable with maximum value  $s$ . In this case, the value of  $X$  in (3) can be increased by up to  $s$ . In the (n-0) network intact state, it will not be needed. but in the (n-2) state such interconnection, although weak, becomes vital, particularly if islanded operation is not permitted. An example of this state is shown in Figure 2. The (n-1) state is more problematic, and needs careful consideration in individual cases. It may be that the value of  $S$  is not constant, with less interconnector capacity being available at times of peak demand (because of

competing demand elsewhere). In this case, (3) would be replaced by (4), where  $s^*$  is taken from a specified, probably time-dependent distribution  $S$  :

$$\begin{aligned} p(X = 2c) &= p_{N-0} \\ p(X = c + s^*) &= p_{N-1} \\ p(X = s) &= p_{N-2} \end{aligned} \quad (4)$$

It may also be that the single circuit capacity  $c$  is sufficient to support peak demand in the present year, but may not be sufficient after a number of years of demand growth, due to new connections or to increased demand from existing customers (due for example to the acquisition of electric vehicles or heat pumps).

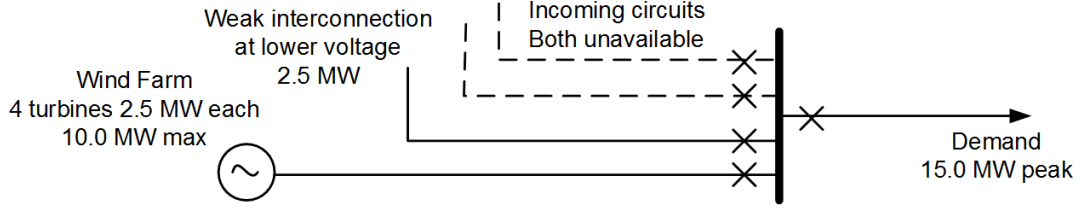


Figure 2 – Weakly-interconnected network

In (2) as in (1),  $D_t$  is the demand profile of the local load. This is usually available with some precision, for example in the distribution network from which the following case study is taken, it is in the form of historic half-hourly data. This can be used directly, or in summary form which quantifies daily, weekly or seasonal peaks and troughs.

Also in (2) as in (1),  $Y_t$  is the generation profile of the local generator. In the case of an already existing wind farm, this could take the form of historic data. If such data is compatible with historic data for  $D_t$ , then the two can be matched for each time period, which will enable dependencies to be recognised, for example a possible peak of wind speed at a time of day such as late afternoon when local demand also peaks. Otherwise, if the distributions for  $Y$  and  $D$  cannot be matched, then estimates of output can be based on samples taken from them independently, for example using Monte Carlo simulation, as has been done in the following case study.

There could also be time dependency between  $X$  and either  $D$  or  $Y$  or both. Over a whole year, this would be evident for example in the policy to schedule planned maintenance of a single supply circuit during the summer period where demand is generally lower than in winter. Such dependencies could be incorporated into the calculation of expected values either explicitly or implicitly by considering each state separately.

Using (2) to evaluate an appropriate value of capacity credit involves first evaluating the right hand side of the equation for the network without generation to derive a base level of energy unsupplied [ $EENS$ ], designated  $u_0$ . The calculation is then repeated with the generation included, which would give a generally lower value of [ $EENS$ ], designated  $u_Y$ . The difference between them is measured in average MWh:

$$u_0 - u_Y = E[(D - X)_+] - E[(D - X - Y)_+] \quad (5)$$

This can be further expanded to separate out the (n-0), (n-1) and (n-2) states. In the generic case of two incoming circuits each of capacity  $c$ , and without any lower voltage infeed  $S$ , (5) becomes

$$\begin{aligned} & (p_{N-0})(E[(D-2c)_+] - E[(D-2c-Y)_+]) \\ & + (p_{N-1})(E[(D-c)_+] - E[(D-c-Y)_+]) \\ & + (p_{N-2})(E[(D)_+] - E[(D-Y)_+]) \end{aligned} \quad (6)$$

With lower voltage interconnection  $S$ , the expression (6) would also need to include  $S$ , at least in the (n-2) term. However, in practice some of the components of (6) will reduce to zero. In particular, the energy unsupplied in the network intact state should generally be zero, both with and without generation, so the top line of (6) will vanish. Other simplifications will become apparent in the following case study.

This expression for the reduction in EENS is useful in some ways, in particular in that it permits the contributions of the wind farm in the (n-1) and in the (n-2) states to be compared. It also distinguishes between the absolute value of generation in rural and urban areas, with their very different underlying rates of circuit failure and consequent network reliability.

The final step in the calculation can be carried out once  $d^*$  has been calculated, in particular in the situation where annual growth in demand can be anticipated and predicted. In this case, the incremental demand  $d^*$ , which can be accommodated as a consequence of embedded generation for no change in overall risk, can be expressed as a number of years of incremental demand, which can in turn be interpreted as a number of years  $n$  for which costly network reinforcement can be deferred. This value  $n$  will be calculated in each scenario of the case study which follows.

## 6. Case Study

The following case study is based on an actual demand group operated by Northern Powergrid in the North of England. Relevant assumptions are as follows:

- Annual demand  $D_t$  follows a triangular probability density function, with maximum demand  $d$  MW in year 0 (taken to be 2012), mean demand  $0.75d$  MW, and minimum demand  $0.5d$  MW. Expected load growth equates to an annual increase  $\Delta d$  (normally set at 1.0 MW) at all times of day, week and year. This is shown in Figure 3, with  $d = 120$  MW.
- Incoming circuit capacity at high voltage (132 kV) consists of two identical circuits each with thermal rating  $c$  MW. Initially, it is assumed that there is no lower voltage interconnection, although later scenarios will evaluate the impact of such interconnection. Figure 4 shows these circuits in the (n-1) condition with  $c = 120.0$  MW.
- Overall circuit availability excluding planned downtime is 99.992% for each circuit, based on an expected fault rate of 0.35 per year and an average customer restoration time of 2 hours. However, 20% of all faults affect both circuits (n-2). These values are consistent with national results in [38].
- The embedded generation whose contribution is to be evaluated consists of a 10 turbine wind farm, of rated capacity 25.0 MW, and output distributed as shown in Figure 5, giving a mean capacity factor of 0.367, which is a typical

winter value for GB high altitude locations. This distribution combines the availability of a discrete number of turbines ( $n=10$ ) with the wind speed distribution for the proposed location. The distribution is based on actual data gathered from November 2011 to February 2012 from a 6.0 MVA wind farm which is connected to the case study network in the North of England. When the whole year is under consideration, the output is scaled down by a factor of 0.8.

- The calculations which follow are explicitly deterministic rather than probabilistic, although they have a probabilistic basis, following the methodology of P2/6. So the results are quoted as the number of years for which reinforcement could justifiably be deferred, such as might be used by Distribution Network Operator planning engineers.

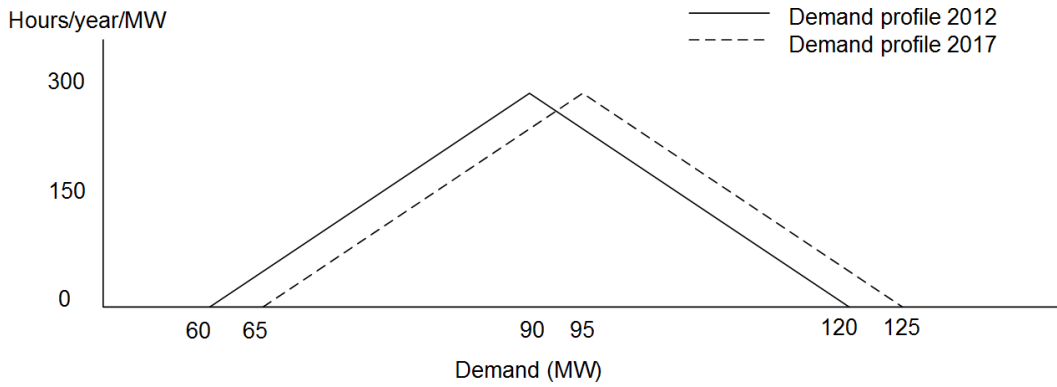


Figure 3 – Demand profile for case study

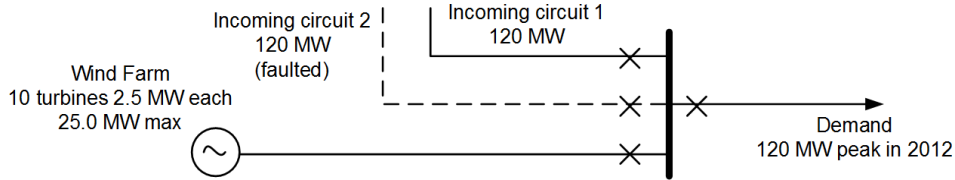


Figure 4 – Network for case study

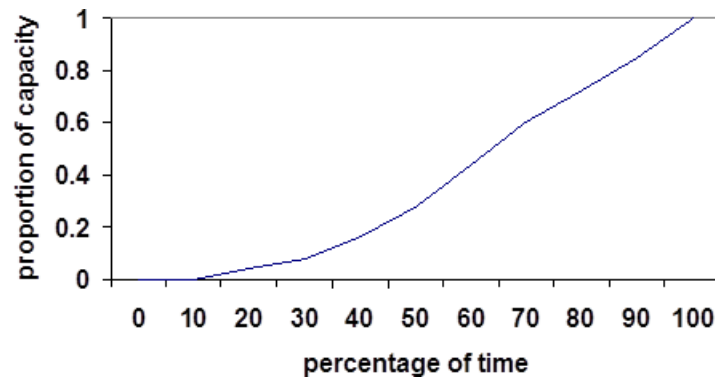


Figure 5 – Cumulative distribution of wind generator output

Calculating values of  $u_0$  and  $u_y$  in this case study depends on which rows of (6) are to be included in the calculation, which itself depends upon the precise requirements of P2/6, as set out in Table 1, and as illustrated in Figure 6. In scenario

A, with  $c = 90$  and  $D_{\max} = 90$  (and assuming  $s = 0$ ), the network is critical for (n-1) events according to P2/6, because with the loss of a single circuit, any increase in maximum demand would lead to some customers at peak times being disconnected, and they could not always be restored within 3 hours as required by P2/6. But the network is not critical for (n-2) events, for which P2/6 does not specify security requirements for levels of  $D_{\max}$  below 100 MW, which allows for 10 years of 1.0 MW annual load growth. Therefore, in keeping with the letter of P2/6, EENS is calculated for the (n-1) state only in Scenario A.

In scenario B, with  $c = 110$  and  $D_{\max} = 100$ , the opposite is true. The network is not critical according to P2/6 for (n-1) events, as there is still 10 MW headroom on a single circuit, enough for 10 years of 1.0 MW annual load growth. But it is critical for (n-2) events as any increase in demand will take  $D_{\max}$  above the threshold value of 100 MW. Therefore, again in keeping with the letter of P2/6, EENS is calculated for the (n-2) state only in Scenario B.

Finally, in scenario C, with  $c = 100$  and  $D_{\max} = 100$ , the network is critical for both (n-1) and (n-2) events, so both lines of (6) should be included in the calculation. In keeping with the letter of P2/6, EENS is calculated for both the (n-1) state and the (n-2) state in Scenario C.

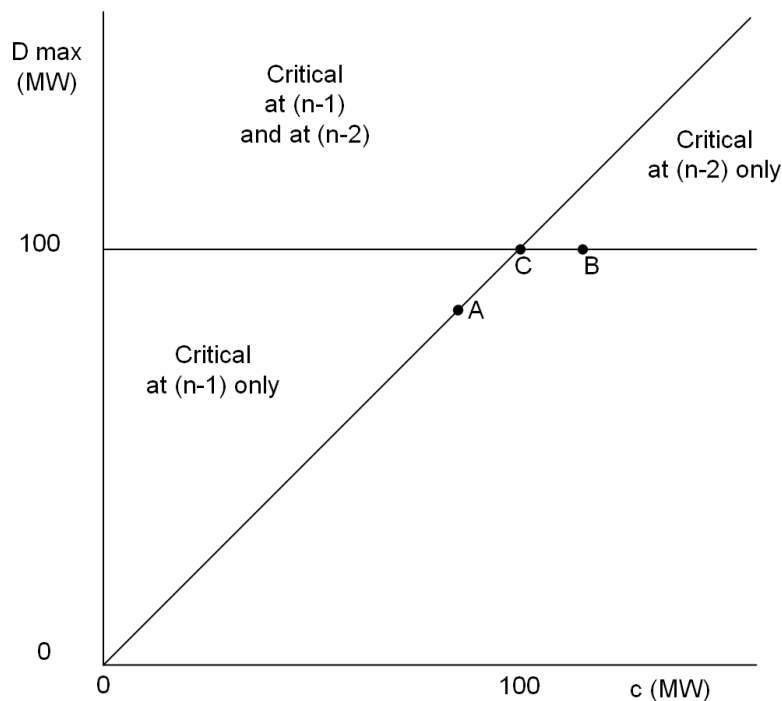


Figure 6 – P2/6 criticality as a function of  $c$  and  $D_{\max}$

#### Scenario A: Critical at (n-1) only, so based on $p_{n-1}$

The value of  $u_0$  increases with time, following a cubic relationship, as shown in Figure 7. This is because  $u_0$  is a product of the number of hours of shortfall, which, being taken from the tail of a triangular distribution, is a quadratic function of time, multiplied by the average value of the shortfall, which is linear with time. The

absolute value of  $u_0$  is small, however (0.0324 MWh in year 5 for example) because it is also multiplied by  $p_{N-1}$ , which is only 0.00016.

The reduction in  $u_0$  as a result of generation is used to calculate  $u_y$ , and is found using Monte Carlo simulation, using a simulated 10000 year period. This allows the probabilistic nature of the calculation to be incorporated in deriving a deterministic result. In year 1, generation can make up 80% of the expected shortfall, so  $u_y$  is only 20% of  $u_0$ . This high figure occurs because the shortfall is only 1.0 MW at most, and the wind generators can supply this quantity of power on 80% of occasions when it is needed. Winter values for generation are used, as shortfalls due to (n-1) events are assumed to occur only during the winter season when demand is at its peak. In subsequent years, the proportion of shortfall which generation can supply decreases somewhat, falling to 72% by year 5, and to 66% by year 10. The calculated values of  $u_y$  are shown alongside those of  $u_0$  in Figure 7.

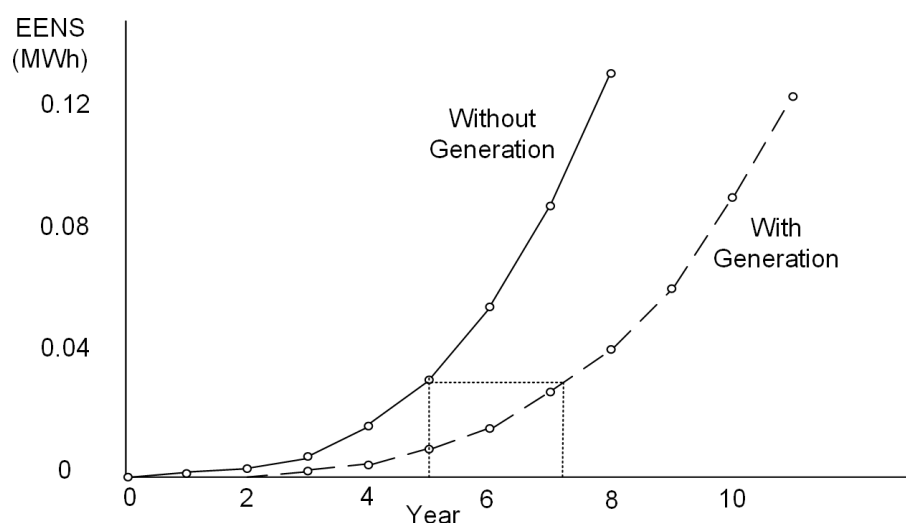


Figure 7 – Effect of generation on EENS in (n-1) scenario

The effect of the difference in EENS, equal to  $u_0 - u_y$ , is shown by the dotted line construction in Figure 7. At year 5, for example, the value of  $u_0$  can be read from the graph as 0.0324 MWh. The same value of EENS on the  $u_y$  curve corresponds to a time of 7.2 years. Therefore the value of  $n$ , the time for which capital expenditure on network reinforcement can reasonably be deferred on account of the wind farm, comes to 2.2 years.

The confidence interval surrounding this value of 2.2 years can be calculated, but it depends on the uncertainty of all the input data, including for example the expected rate of load growth. By using a large number of simulated years ( $n=10000$ ), and reasonable input assumptions, a 90% confidence interval for the expected value of + or – 0.4 years was calculated, taking into account uncertainties in load growth, circuit failure rates and generator capacity factor.

#### Scenario B: Critical at (n-2) only, so based on $p_{n-2}$

The value of  $u_0$  again increases with time, but in this scenario it follows a linear relationship, as shown in Figure 8. This is because under (n-2) conditions,  $u_0$  is

the total energy demand (averaged across the year), incremented by a constant 1.0 MW per year, and multiplied by  $p_{N-2}$  which is 0.00004.

The difference made by the generator depends on whether operation as a power island is possible. If not, as is generally the case for wind generators without sophisticated control, then there is no benefit to be gained from the embedded generators under (n-2) conditions. It is therefore assumed that a small quantity of lower voltage infeed,  $s = 5.0$  MW is available at all times.

Since the minimum demand (50 MW), less lower voltage infeed, is greater than the maximum output of the wind farm (25 MW), the full output of the wind farm can be used to reduce EENS at all times. The effective value of this must be averaged across the whole year, so the winter output assumed in Scenario A must be reduced by a factor of 0.8. It has been assumed that the capacity factors used incorporate generator unavailability as well as wind intermittency. The reduced value of EENS due to generation  $u_y$  is also shown in Figure 8, as is the dotted line construction for calculating  $n$ . Two contrasts with Scenario A are apparent. First, the values of EENS are higher by a factor of around 600. This reflects the fact that, although an (n-2) event is less likely than an (n-1) event by a factor of 4, it causes a loss of energy whenever it occurs (not just at times of extreme peak demand), and the energy shortfall when it does occur is also much greater. The second contrast is in the value of  $n$ , which (calculated in Year 5) is around 7 years for the period considered, compared to around 2 years when considering (n-1) alone, as in Scenario A.

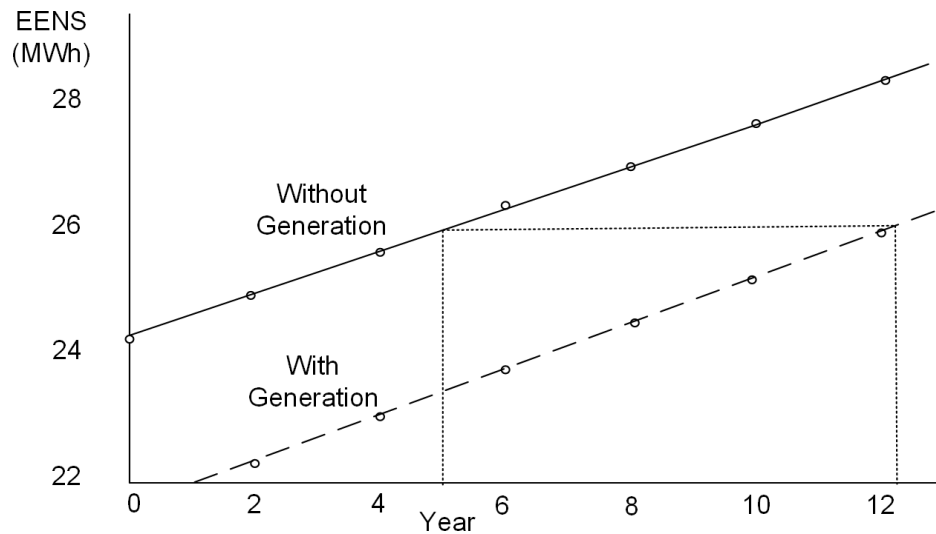


Figure 8 – Effect of generation on EENS in (n-2) scenario

### Scenario C: Critical at both (n-1) and (n-2)

Where both (n-1) and (n-2) events are critical, the values of EENS must be added for the two events. However, in the present case study the (n-2) values dwarf the (n-1) values by a factor of around 600. The relative contribution of the (n-1) component in this scenario is therefore of second order, and can be ignored in evaluating  $n$ , which would be around 7 years as in Scenario B.

It is instructive to compare the values calculated for  $n$  with the value calculated using the methodology of P2/6. That methodology would simply multiply the 25 MW nameplate capacity of the wind farm by the appropriate F-factor, probably 0.24 for a persistence of 3 hours, to give a capacity credit of 6.0 MW, equivalent to



$n = 6$  years at an annual peak demand growth of 1.0 MW. This is below the (n-2) value, but well above the (n-1) value, calculated using the methodology of the present paper. Perhaps more by accident than design, the outcomes of these two very different methods are very similar.

## 7. Conclusions

This paper has shown that wind generation has the potential to increase security of supply to customers of distribution networks under a number of different scenarios. In certain circumstances, the level of increased security can be used to defer costly network reinforcement construction projects, which may also be visually intrusive and disruptive during the construction phase, although the reasonable duration of such deferral depends on the method used to calculate capacity credit.

While some countries do not use explicit design standards for system security, others do, including GB whose P2/6 standard specifies the security required in the separate cases of both (n-1) and (n-2) events. This standard also makes specific allowance for the capacity credit to be allowed for embedded generation, including wind generation. The calculation of allowed credit takes into account the capacity of the wind farm and the required persistence. However, it does not take into account a number of other significant factors relating to the topology, loading and reliability of the surrounding network.

Therefore this paper has developed an alternative methodology for evaluating capacity credit, which integrates generation with load, and derives a realistic estimate of the number of years for which costly network reinforcement can reasonably be deferred as a consequence of embedded generation. The estimate is deterministic, as required by P2/6, but could in each case be given confidence intervals which would be a function of the uncertainty of the input data. This methodology is illustrated by a case study based on an actual part of the network in the North East of England. It concludes that, under a specified set of assumptions, the deferral time could range from 2 years to 7 years, depending on the precise relationship between circuit capacity and group demand profile, and on how these factors relate to the output profile of the wind generators. It is acknowledged that the limited number of wind turbines, and other circuit assets, introduces a granularity into the analysis which in turn affects the confidence level of the results. It is noted that the outcome is similar to that achieved using the current planning standard (which would permit deferral by around 6 years), although this may be fortuitous.

There are proposals within the GB industry to revise the P2 standard over the next 2-3 years [40], and it is to be hoped that this paper can make an effective contribution to this fundamental policy review by addressing the important issue of appropriate capacity credit for wind farms.

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